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Kerr et al.

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(54) **STEAM ANTI-CONING/CRESTING TECHNOLOGY (SACT) REMEDIATION PROCESS**

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Related U.S. Application Data

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(51) **Int. Cl.**
E21B 43/24 (2006.01)
E21B 43/32 (2006.01)

(52) **U.S. Cl.**
CPC **E21B 43/24** (2013.01); **E21B 43/32** (2013.01); **E21B 43/2408** (2013.01)

(58) **Field of Classification Search**
CPC E21B 43/16; E21B 43/24; E21B 43/243; E21B 43/2408; E21B 43/30
See application file for complete search history.

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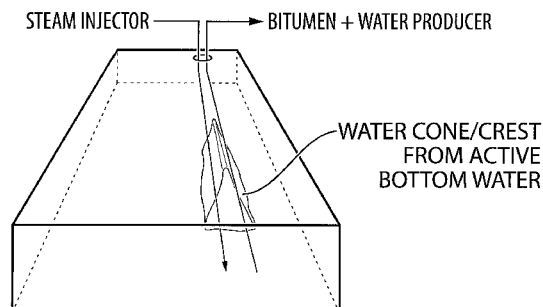
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(57) **ABSTRACT**

A cyclic remediation process to restore oil recovery from a primary oil production well that has watered off from bottom water encroachment (cone or crest) whereby: (a) the primary oil production well has a produced water cut in excess of 95% (v/v); (b) the oil is heavy oil, with in-situ viscosity >1000 cp; wherein the process includes: (c) injecting a steam slug with a volume of 0.5 to 5.0 times the cumulative primary oil production, with steam volumes measured as water volumes; (d) shutting in the well for a soak period, after the steam injection is complete; and (e) producing the well until the water cut exceeds 95%.

14 Claims, 18 Drawing Sheets



SAGD PARTIAL CONING/CRESTING

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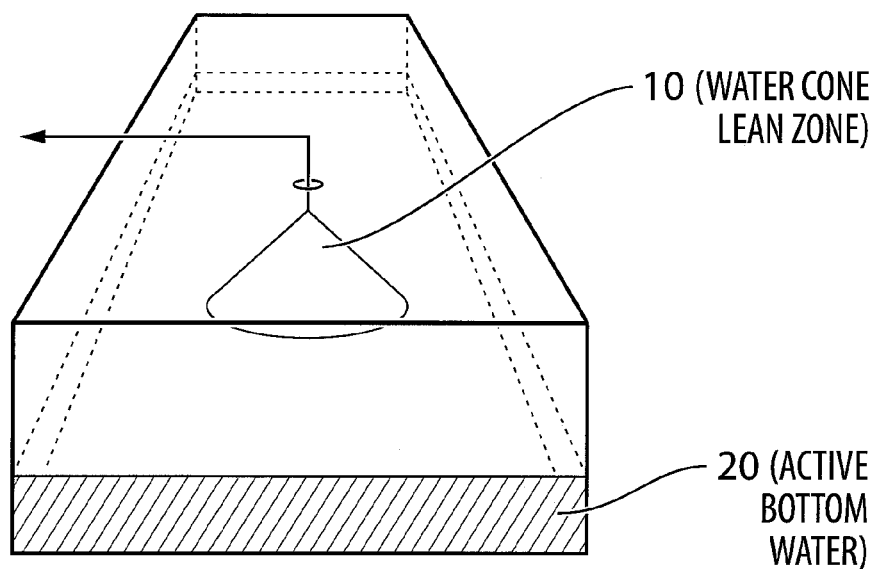
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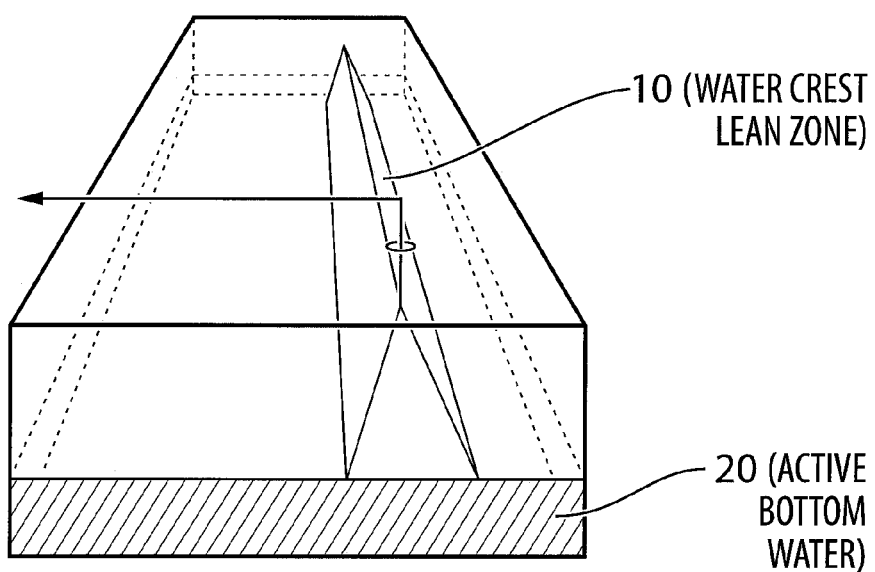
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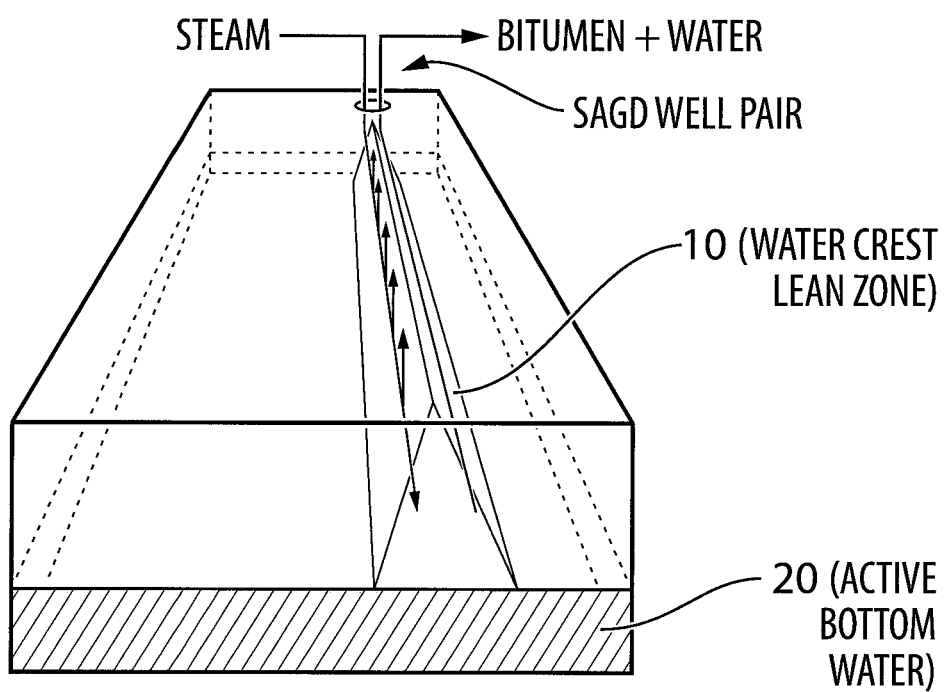
1A. VERTICAL PRODUCTION WELL



1B. HORIZONTAL PRODUCTION WELL

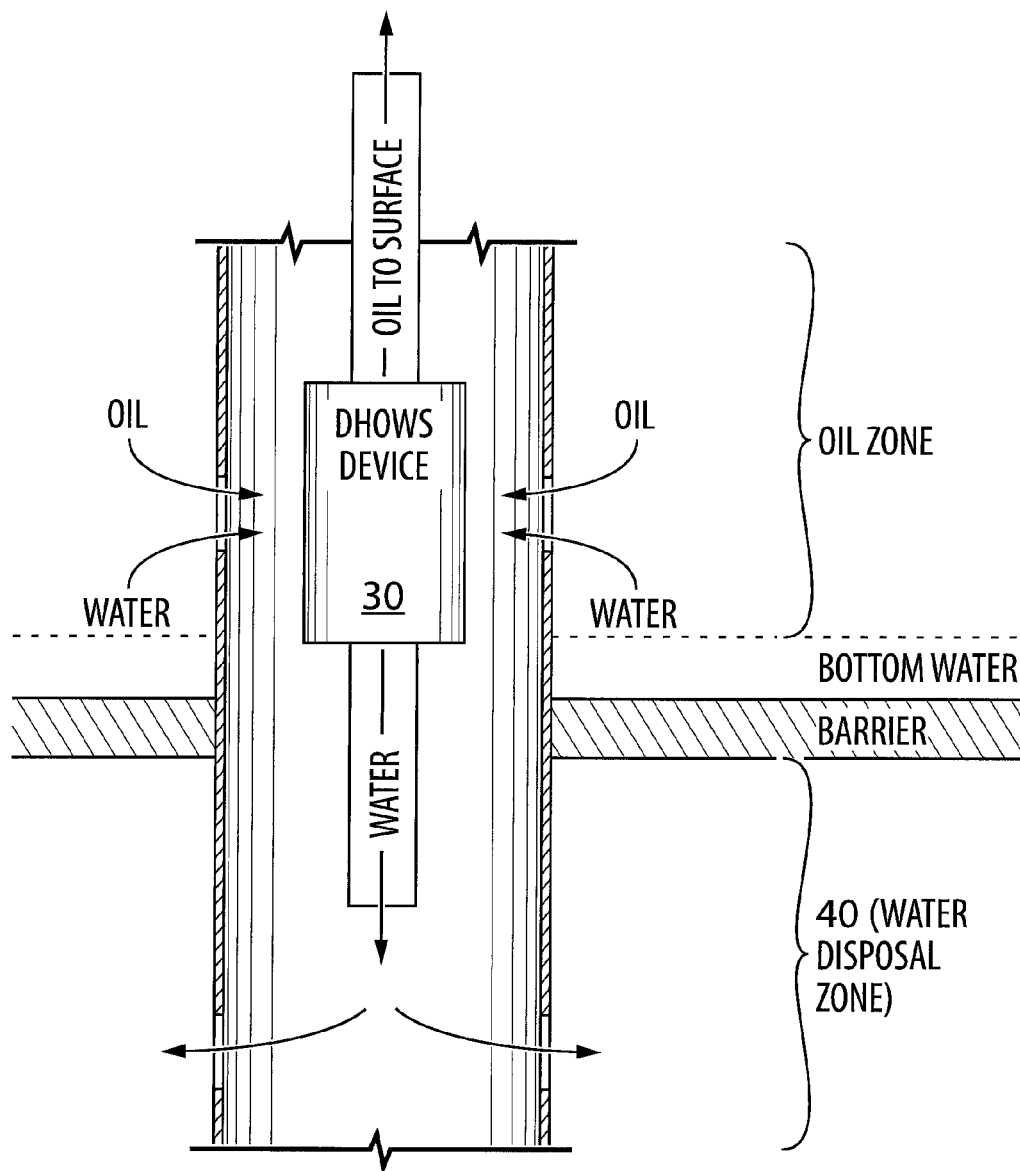
CONES/CRESTS LEAN ZONES

FIG.1



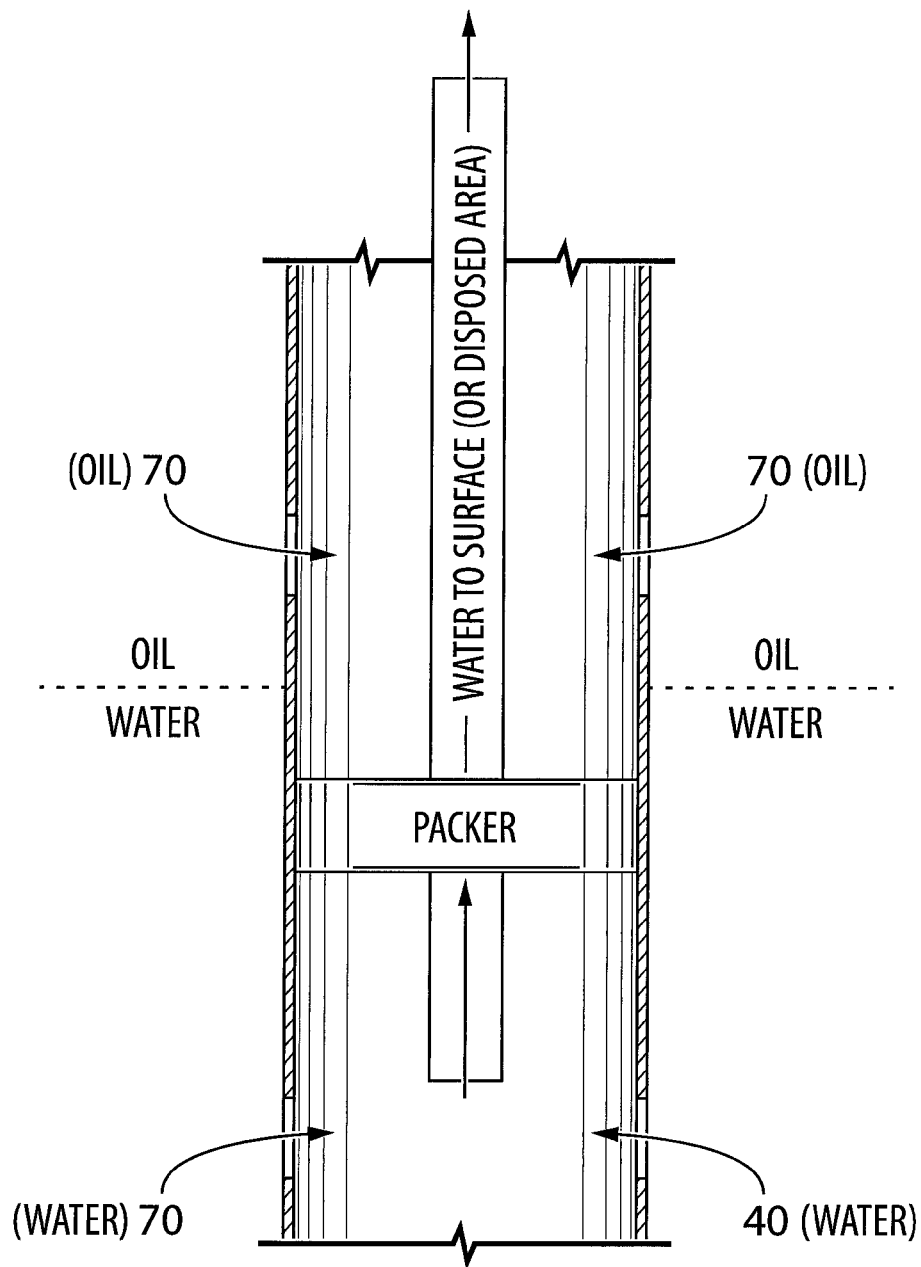
SAGD BITUMEN LEAN ZONES (BOTTOM WATER)

FIG.2



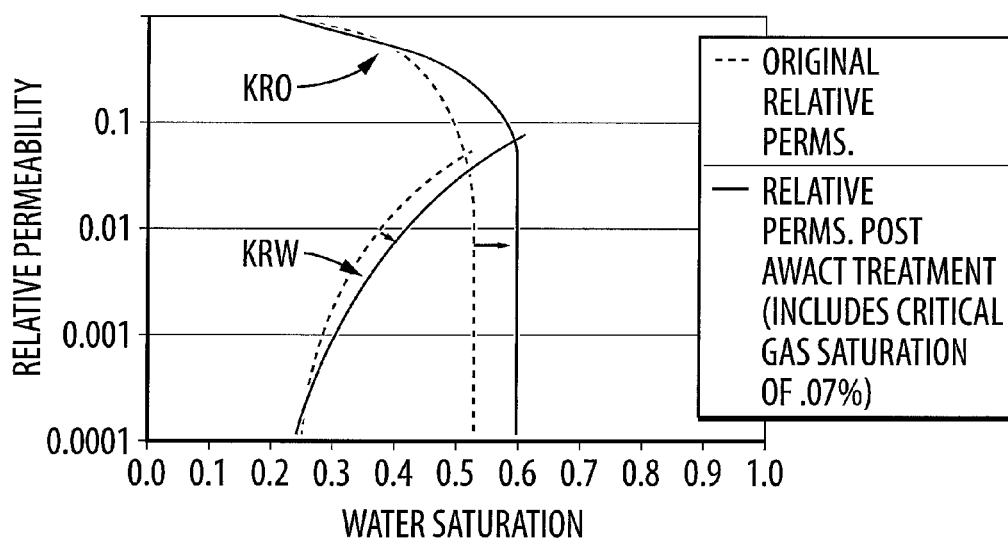
THE DHOWS CONCEPT

FIG.3



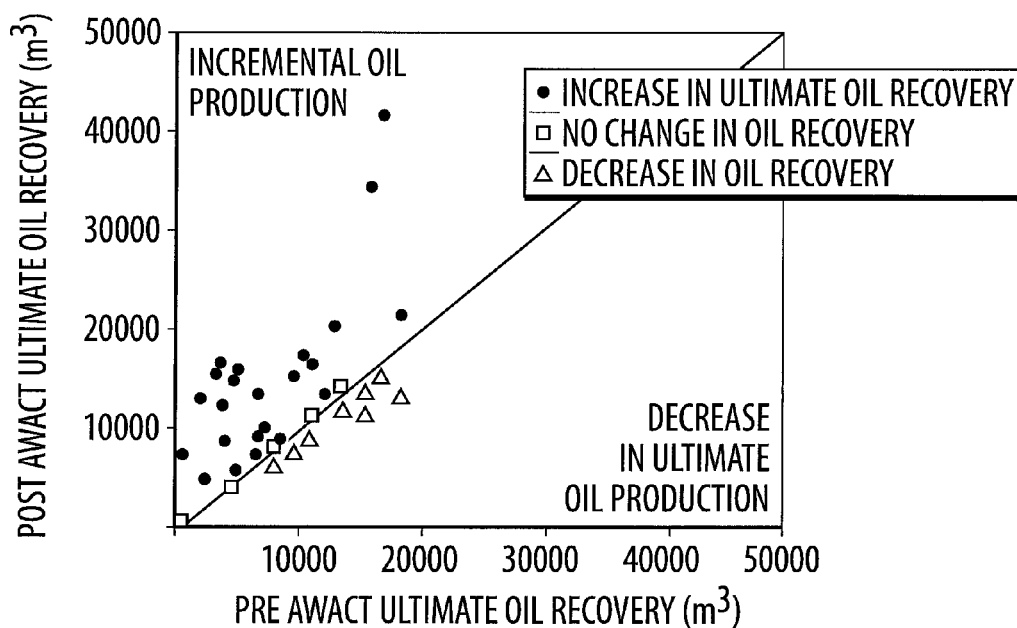
REVERSE CONING CONTROL

FIG.4



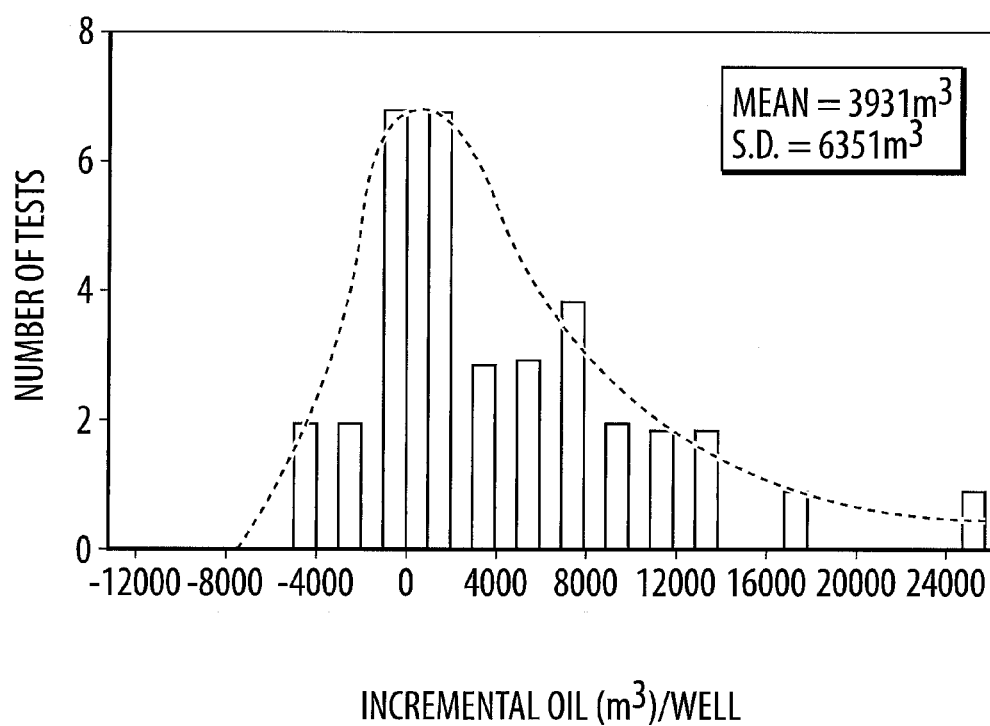
AWACT EFFECTS ON RELATIVE PERMEABILITY

FIG. 5



PRE AWACT VS POST AWACT OIL RECOVERY

FIG. 6

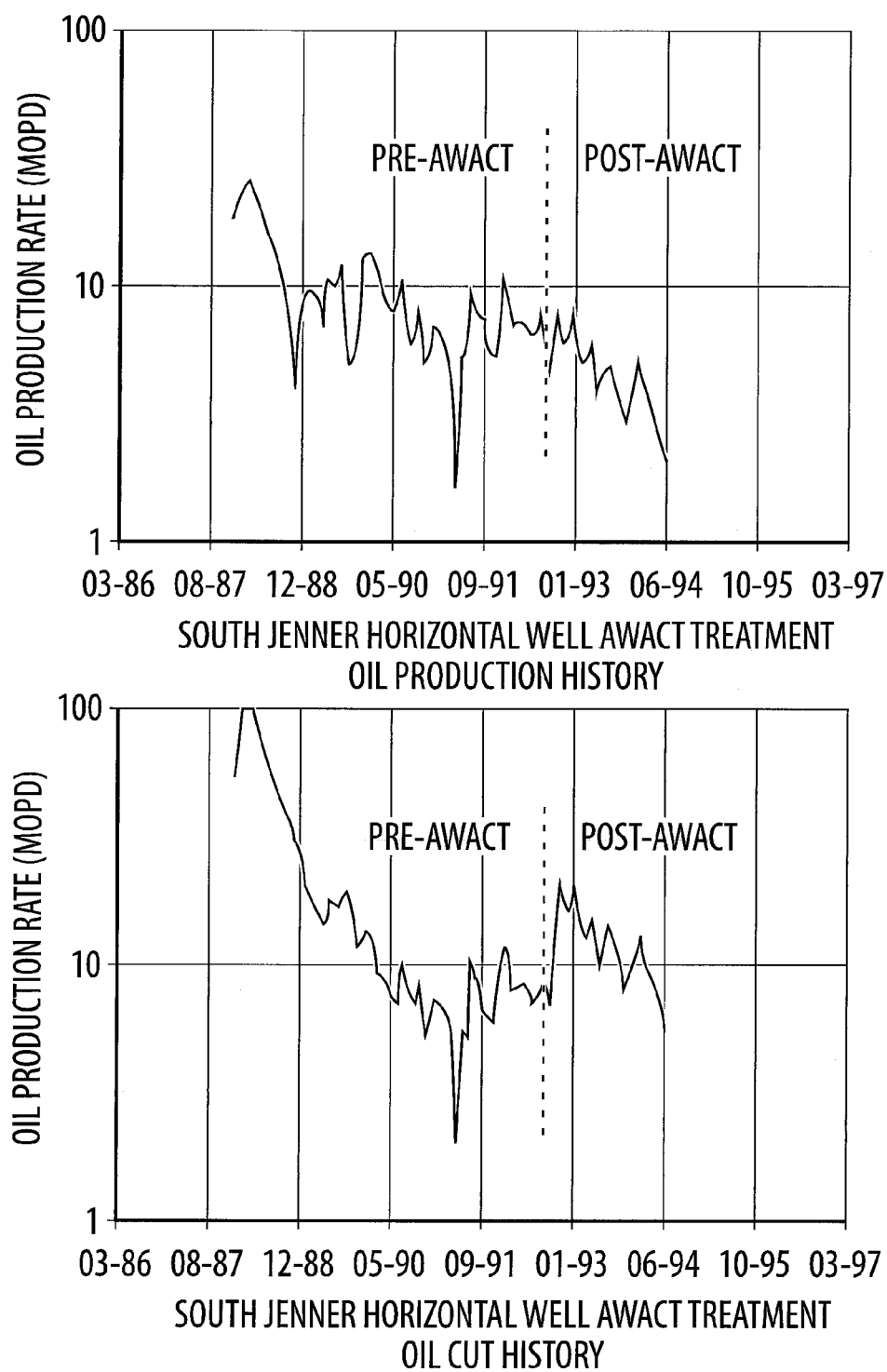


INCREMENTAL OIL (m³)/WELL

FREQUENCY DISTRIBUTION INCREMENTAL OIL
FOLLOWING AWACT

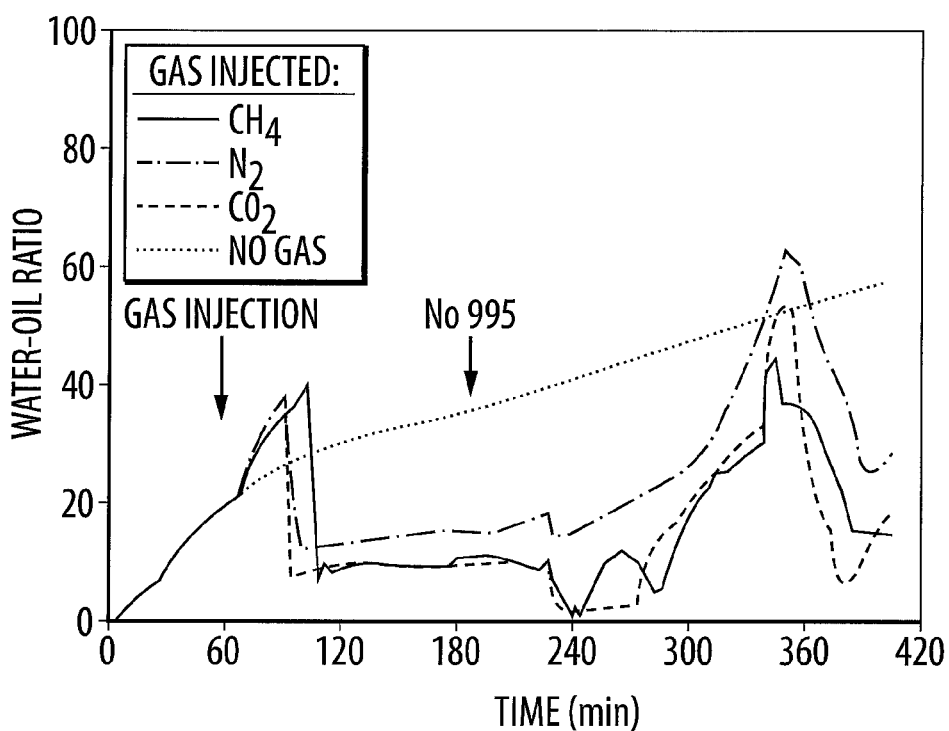
INCREMENTAL AWACT RESERVES

FIG.7



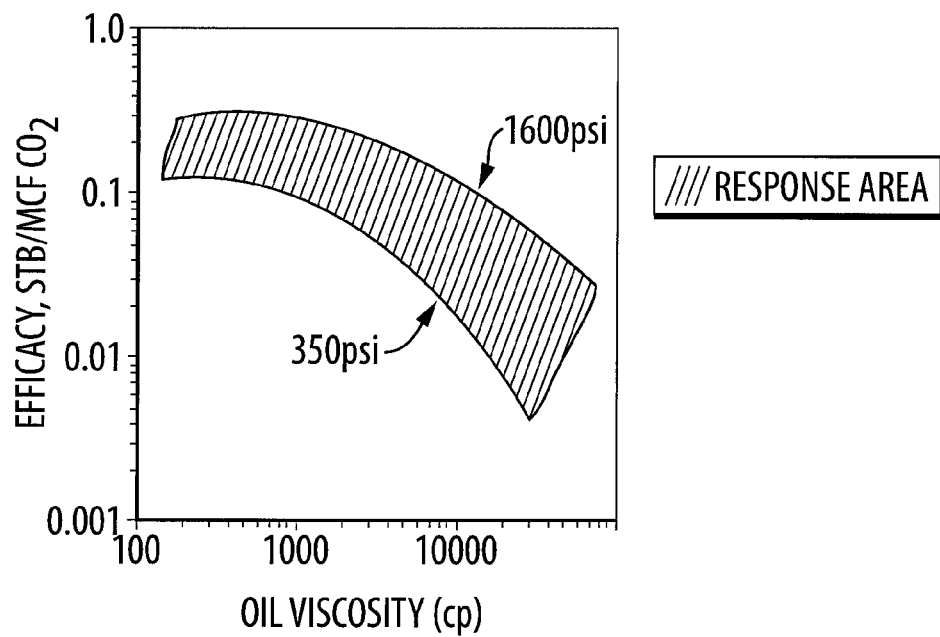
AWACT ON HORIZONTAL WELLS

FIG.8



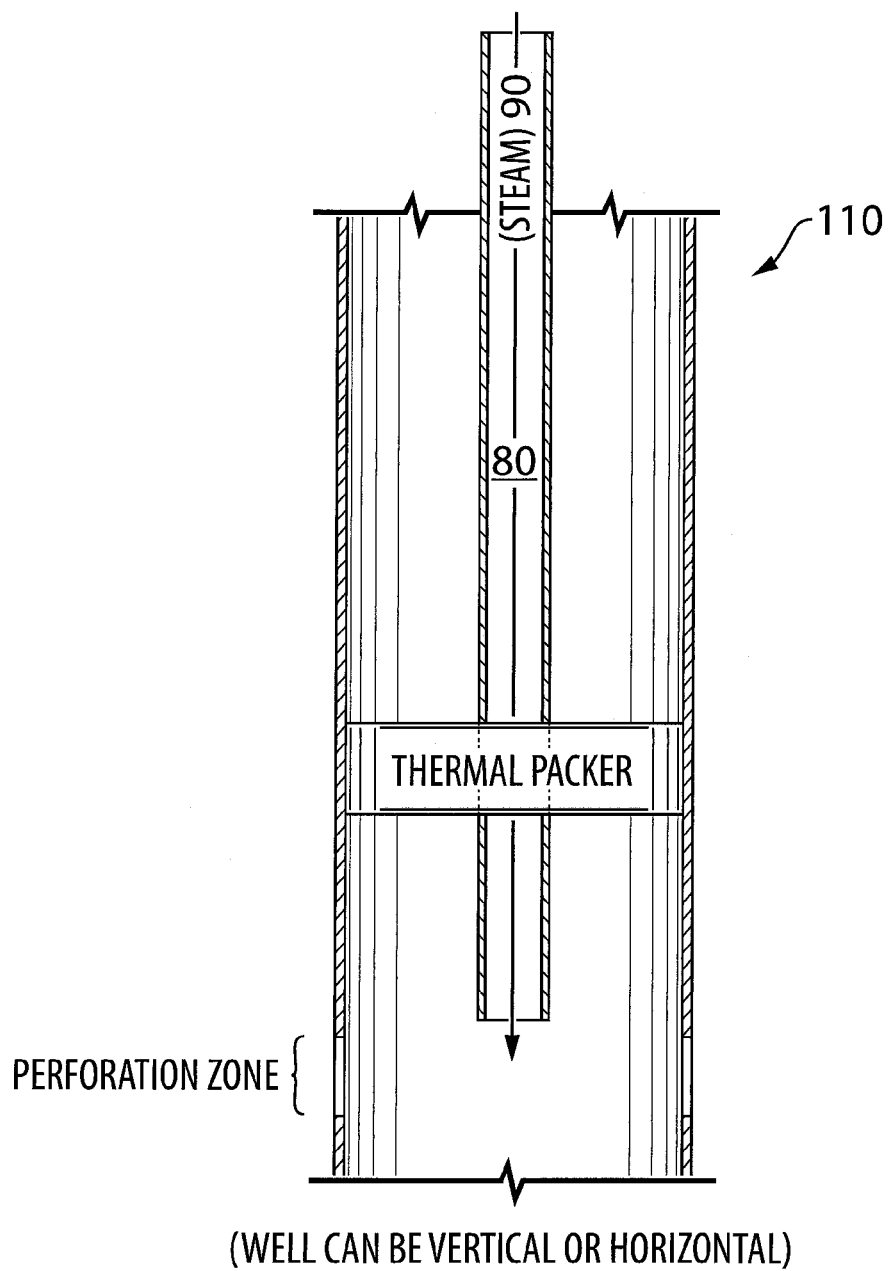
CHOICE OF AWACT GASES - AWACT LAB TESTS

FIG.9



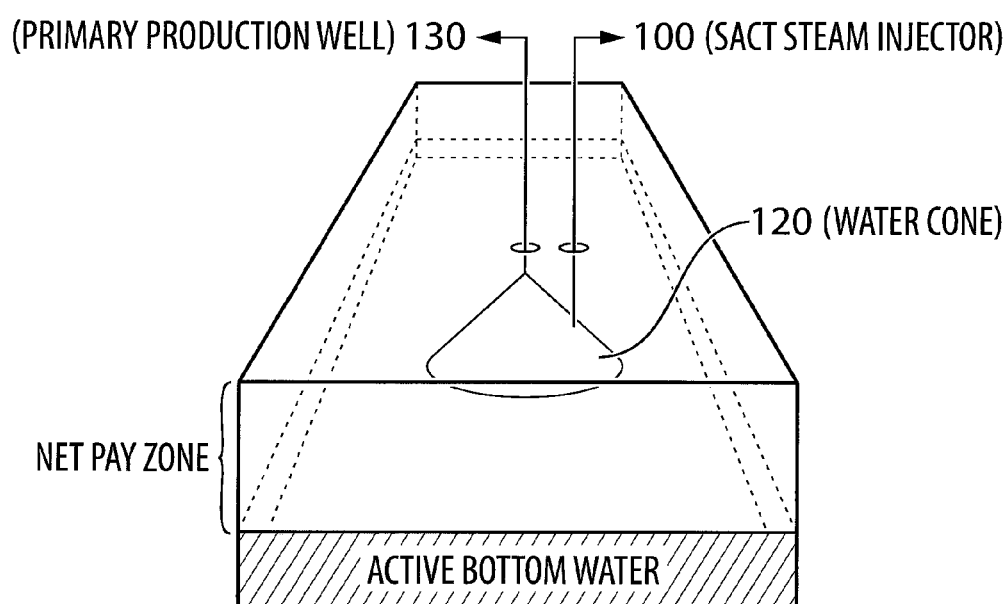
CYCLIC CO₂ STIMULATION OF OIL WELLS

FIG.10



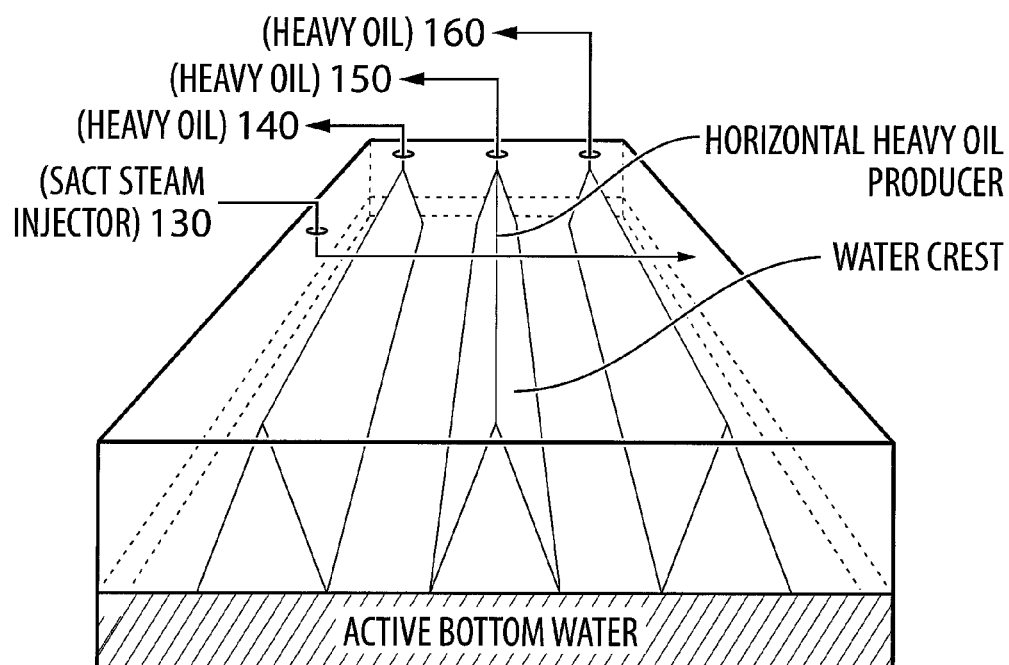
STEAM STRING FOR SACT

FIG.11



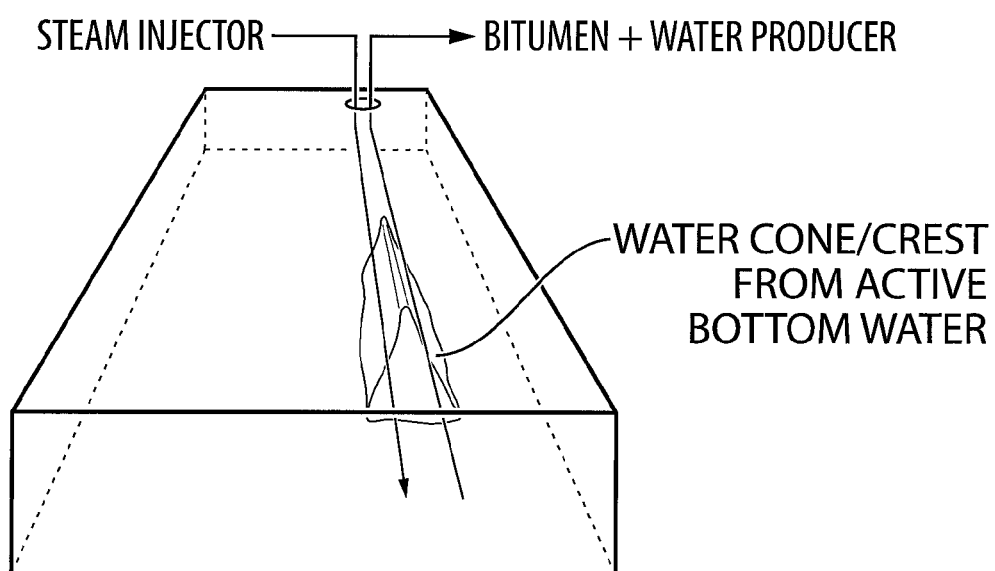
SEPARATE STEAM INJECTOR FOR SACT

FIG.12



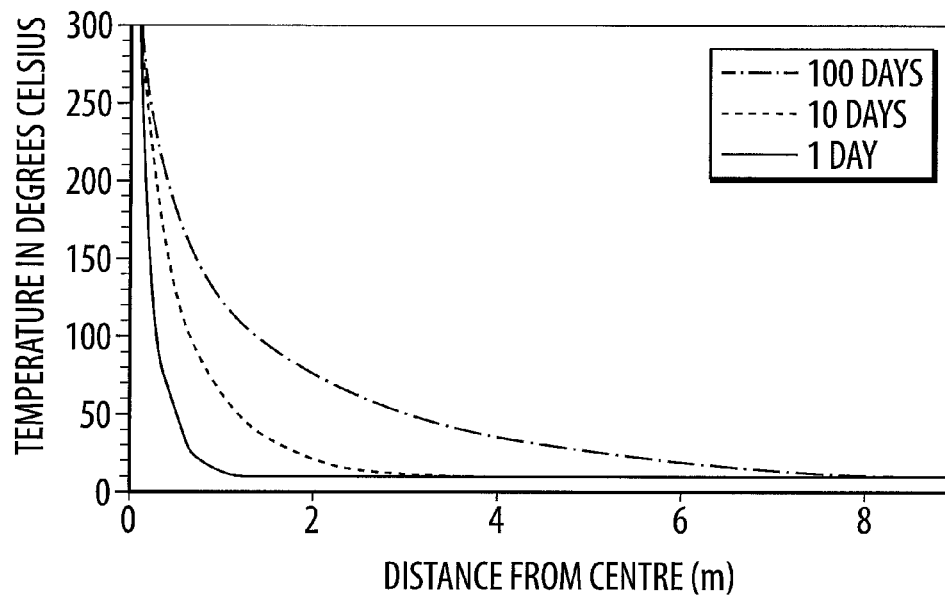
SACT WELL FOR CRESTED HEAVY OIL WELLS
(STEAM ANTICONING/CRESTING TECHNOLOGY)

FIG.13



SAGD PARTIAL CONING/CRESTING

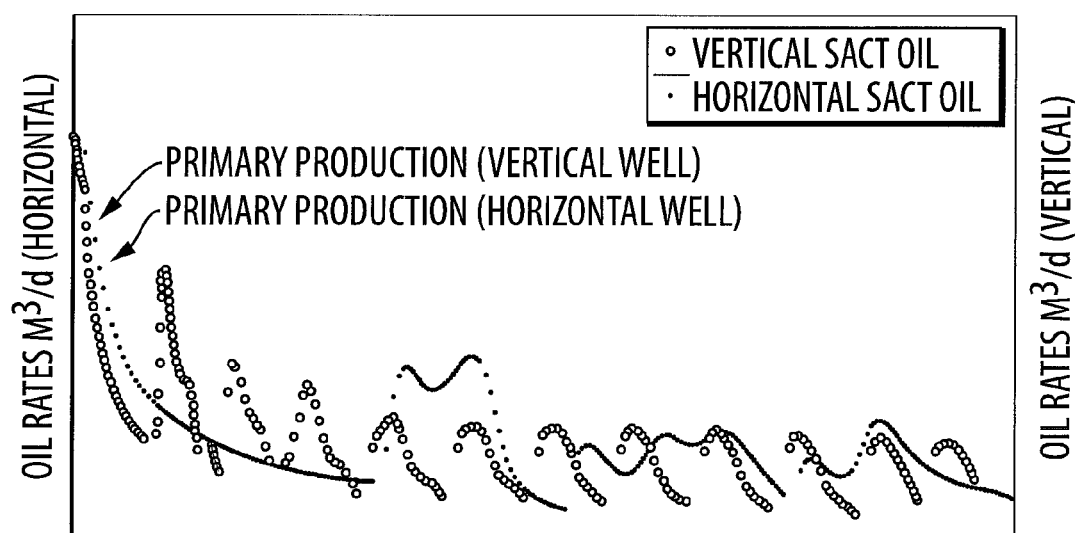
FIG.14



WHERE: (1) RESERVOIR T=10 DEGREES CELCIUS
(2) STEAM P=10mPa
(3) STEAM Q=70%

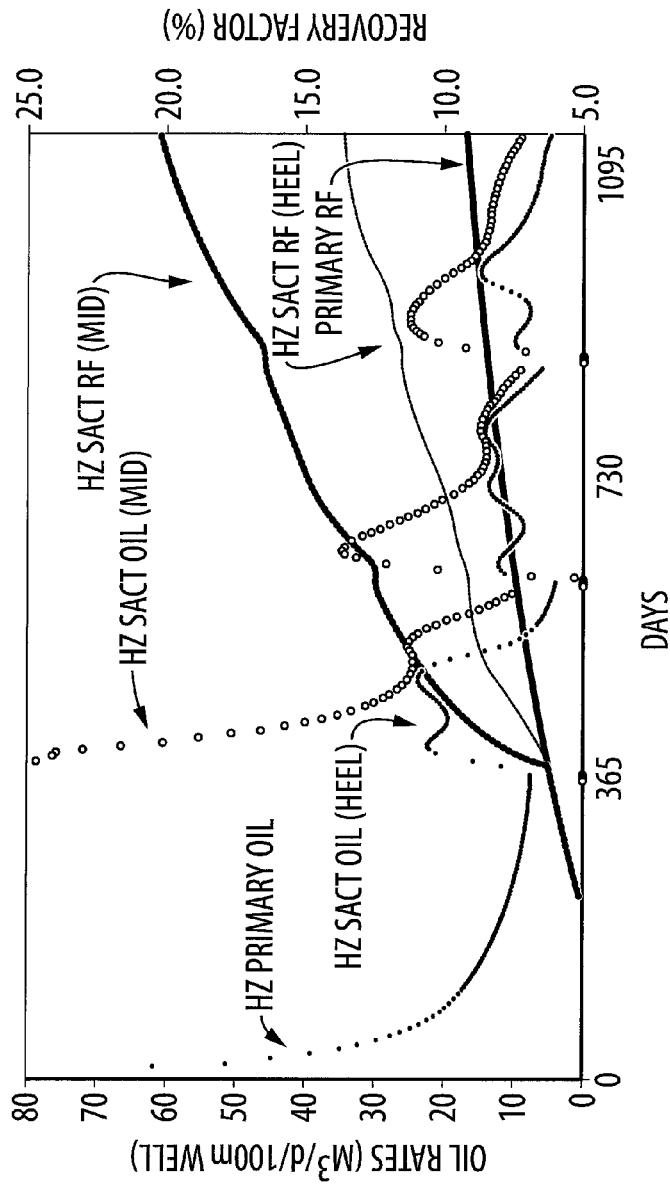
HEAT CONDUCTION AROUND A HOT WELL

FIG.15



SACT SIMULATION VERTICAL VS HORIZONTAL WELLS

FIG.16



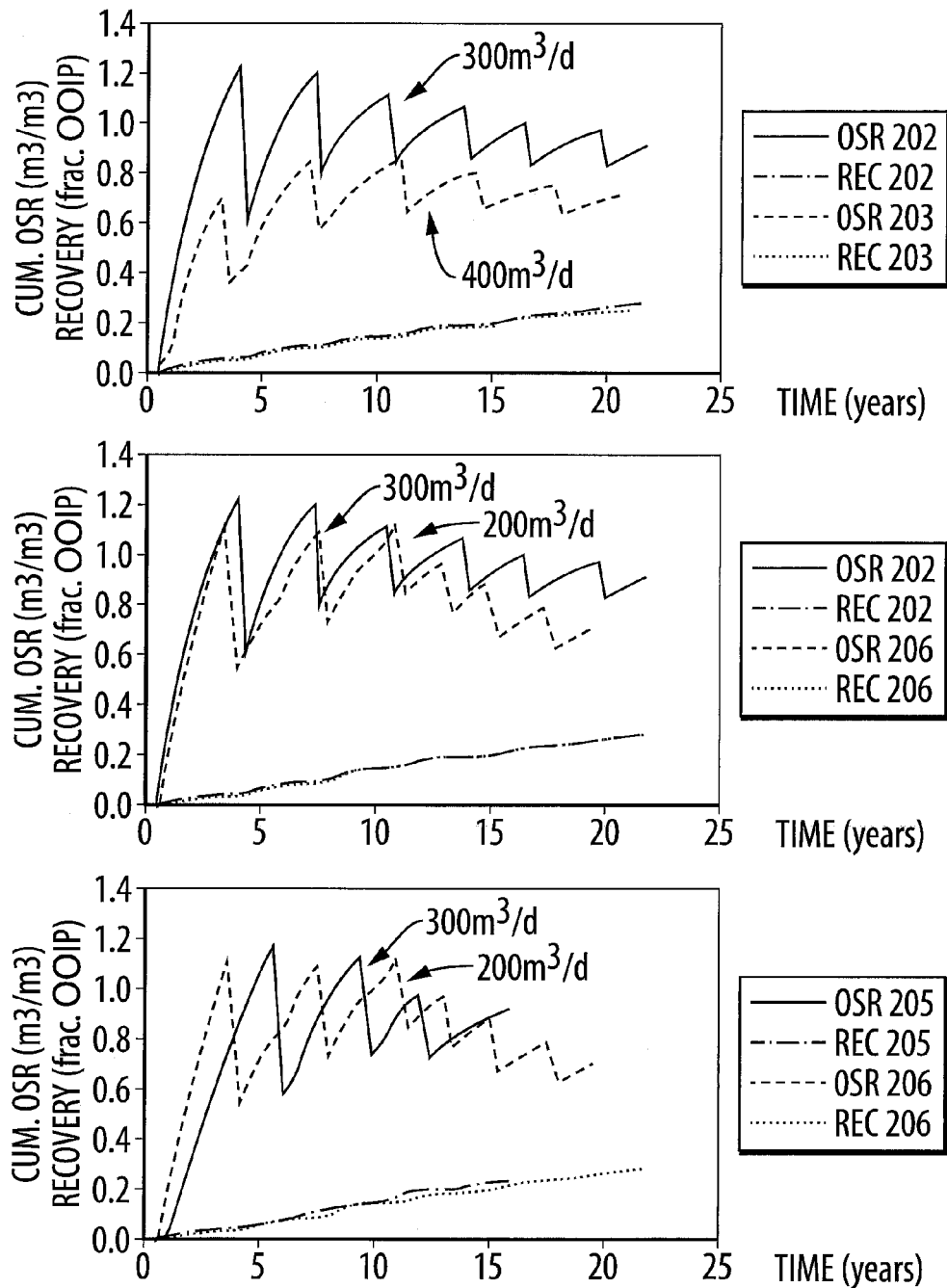
HZ SACT (HEEL) - Steam is injected at the heel of the horizontal producer into the crest zone

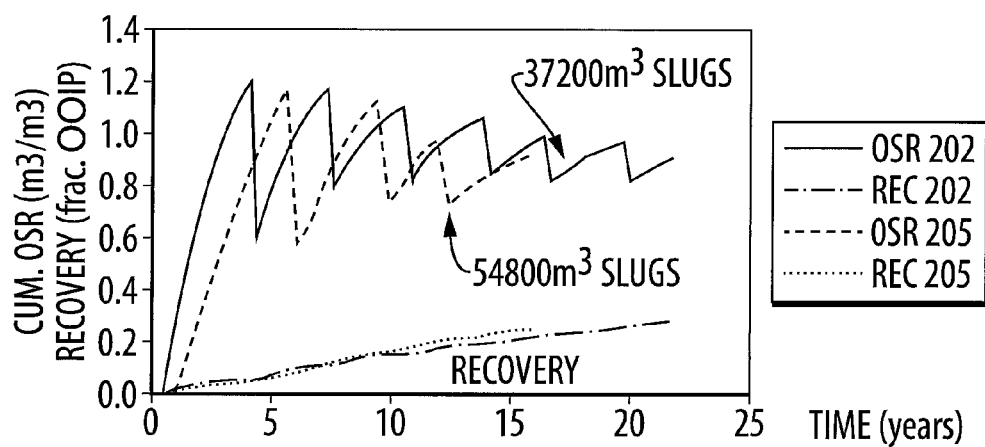
HZ - Horizontal Well

HZ SACT (MID) - Steam is injected at the mid point of the horizontal producer into the crest zone

SACT SIMULATION II HORIZONTAL WELLS

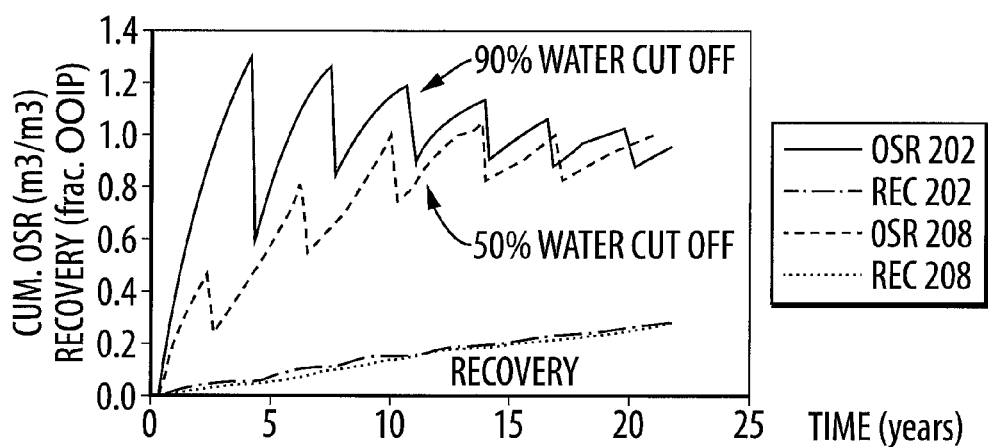
FIG.17

SACT SCALED PHYSICAL MODEL STEAM INJECTED RATES**FIG.18**



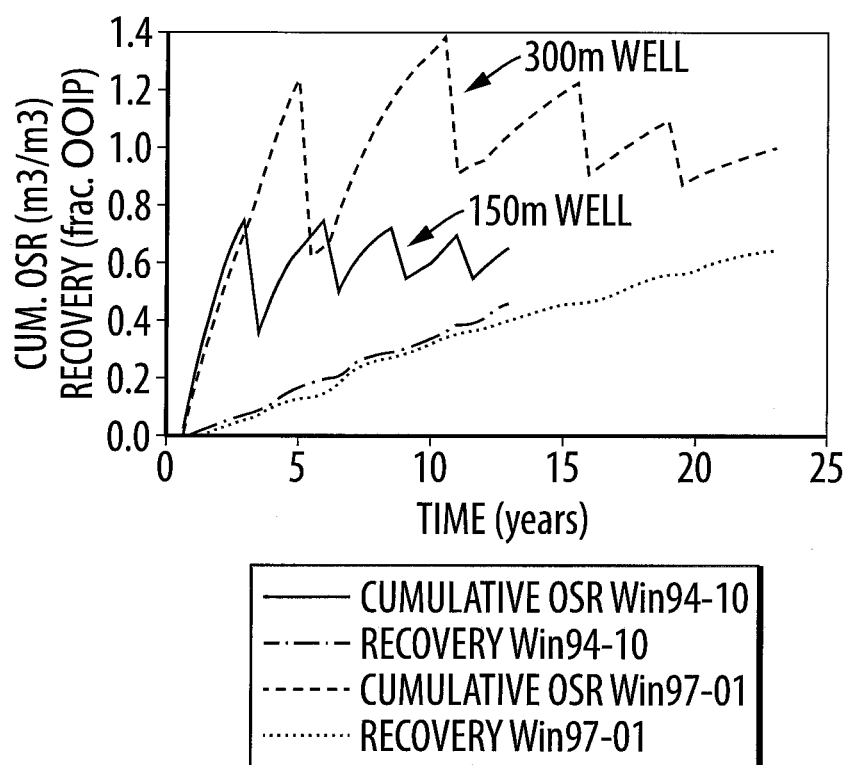
SACT SCALED PHYSICAL MODEL STEAM SLUG SIZES

FIG.19



SACT SCALED PHYSICAL MODEL WATER CUT OFF

FIG.20



SACT SCALED PHYSICAL MODEL HORIZONTAL WELL LENGTHS

FIG.21

STEAM ANTI-CONING/CRESTING TECHNOLOGY (SACT) REMEDIATION PROCESS

BACKGROUND OF THE INVENTION

As illustrated in FIG. 1A, many oil reservoirs have an active bottom water zone **20** beneath a net-pay zone containing oil. If oil, particularly high viscosity in-situ oil, is pumped from a vertical well completed in the oil zone, water can cone up to the production well and inhibit production. In terms of production, coning will reduce oil cuts and increase water cuts until it is no longer economic to produce the well. In the industry, the well is said to have “watered off”. The mobility ratio of the oil determines the rate and extent of water coning. Typically, when the oil is heavier, the worse the water-coning problem is. As illustrated in FIG. 2, the problem may also be exhibited in SAGD for bitumen recovery with bottom water reservoirs.

Attempts have been made to prevent coning/cresting when reservoir characteristics are known. However, these attempts have had limited impact. Examples of attempts include the following:

- 1) The production well is completed higher up in the net pay zone, so the water cone has to be elongated before the well waters off. This is a temporary fix at best, and extra production is often marginal.
- 2) As illustrated in FIG. 1B, a horizontal well is drilled so the pressure drop of pumping is spread over the length of the horizontal well. However, water will eventually encroach to the well and produce a water crest zone **10** of high water saturation. Similar to a vertical well, the well will water off.
- 3) Oil production rates are minimized to delay or prevent coning/cresting
- 4) As illustrated in FIG. 3, downhole oil/water separator **30** (DHOWS) with downhole water disposal is installed. (Piers, K. Coping with Water from Oil and Gas Wells, CFER, Jun. 14, 2005). The downhole device can be a cyclone. This device, however, requires a suitable disposal zone **40** for water, and it works best on light oils with a high density difference between water and oil. This is not practical for heavier oils.
- 5) As illustrated in FIG. 4, a reverse coning system **50** is installed (Piers, 2005). Water **60** and oil **70** are produced or pumped separately in this system to control coning. Again for heavier oils, the water pumping rate to control coning is very large and impractical.

There have also been attempts to limit the coning/cresting when reservoir characteristics are unknown or coning/crest-

ing isn't large enough to justify prevention investments. Known remediation attempts have had limited impact. Examples of these attempts include the following:

- (1) Blocking agents are used to inhibit water flow in the cone/crest zones. Blocking agents include gels, foams, paraffin wax, sulfur, and cement. Each of these have been tried with limited success (Piers (2005)), (El-Sayed, et al., Horizontal Well Length: Drill Short or Long Wells?, SPE 37084-MS, 1996).
- (2) Another reactive process is to shut in the oil well that has coned/crested. Gravity will cause the cone/crest zone to re-saturate with oil. However, when the oil is heavier, the time for re-saturation can be very long and the benefits can be marginal.
- (3) A slug of gas is injected into the cone/crest zone. In the early 1990's, a process called anti-water coning technology (AWACT) was developed and tested in medium/heavy oils (AOSTRA, AWACT presentation, March 1999). The AWACT process involves injecting natural gas (or methane) to displace water, followed by a soak period (Luhning et al, The AOSTRA anti-water coning technology process from invention to commercial application, CIM/SPE 90-132, 1990). Lab tests indicated that the preferred gas (CO₂ or CH₄) has some solubility in oil or water (FIG. 9). The following mechanisms were expected to be activated.
 - a. On the “huff” part of the cycle or when gas is injected, methane displaces mobile water and bypasses the oil in the cone zone.
 - b. On the “soak” cycle or when the well is shut-in, methane absorbs slowly into the oil to reduce viscosity, lower interfacial tension, and cause some swelling
 - c. On the “puff” cycle or when the well is produced, gas forms ganglia/bubbles that get trapped to impede water flow. As illustrated in FIG. 5, this creates a change in relative permeability. Oil cuts are improved and oil production is increased.

However, benefits only last a few years, and the process can only be repeated 5 or 6 times. Table 1 below summarizes AWACT field tests for 7 reservoir types (AOSTRA (1999)). Oil gravity varied from 13 to 28 API, and in situ viscosity varied from 6 to 1200 cp. AOSTRA suggested the following screens for AWACT—1) sandstone reservoir; 2) oil-wet or neutral wettability; 3) in situ viscosity between 100 to 1000 cp; 4) under saturated oil; and 5) greater than 10 m net pay.

TABLE 1

AWACT Reservoir Characteristics										
South Jenner AWACT Treatment Summary (Based on 34 treatments evaluated)										
Well Grouping		Average Production				AWACT	AWACT Net Production		AWACT Gas Slug	
		Pre AWACT		Post AWACT		Duration	m3 oil/m3 water		Size	Ratio
		MOPD	OC %	MOPD	OC %	Months	One Year	Duration	km3	m3m3
1.	All wells	3.0	9.7	2.9	19.9	22	73/(7,900)	315/(17,700)	144	22.0
2.	30 wells with increased OC	3.0	10.0	2.9	21.7	23	102/(8,800)	365/(19,900)	148	22.0
3.	15 wells with increased MOPD	2.5	11.7	3.8	25.5	23	630/(11,100)	1,350/(26,500)	148	25.4
4.	19 wells with decreased MOPD	3.4	7.9	2.2	15.2	21	(370)/(5,400)	(510)/(10,700)	151	20.1

TABLE 1-continued

AWACT Reservoir Characteristics										
5.	14 wells with increased MOPD & OC	2.6	12.0	4.1	27.5	23	650/(11,700)	1400/(27,900)	154	33.0
6.	10 water wetting treated wells	2.9	9.4	3.3	19.0	28	215/(8,700)	600/(24,800)	119	21.4
7.	23 non-chemically treated wells	3.0	9.6	2.8	20.6	19	0/(7,800)	165/(15,000)	167	27.4
() numbers in brackets are negative										
* ratio is m ³ gas per m ³ of cumulative oil production prior to treatment										
Reservoir Characteristics of Other AWACT Treated Pools										
Field	Formation	Net Pay m	Permeability md	Porosity frac.	Water Saturation %	Oil Gravity ° API	Oil Viscosity cp	Pressure kPa	Rsl * m3/m3	
Bellshill Lake	Basal Quartz/Ellerslie	12-13	900	0.23	0.29	28	9.2	5900	20	
Provost	Dina	8.5	1000	0.22	0.35	28	6.5	n/a	30	
Chin Coulee	Taber	7.6	500-1000	0.20	0.30	24	140	8274	n/a	
Suffield	Upper Mannville	16	1000	0.27	0.25	13-14	500	8760	20	
Provost	McLaren	15	1000-5000	0.31	0.30	13	1200	n/a	14	
Jenner	Upper Mannville	12-16	1000-2000	0.26	0.27	15-17	66	8010	33	
Grassy Lake	Upper Mannville	16-17	1000-2000	0.27	0.23	17-19	76	9600	11	

* Initial Reservoir GOR

As illustrated in FIGS. 6 and 7, AWACT was not always a success (Lai et al., Factors affecting the application of AWACT at the South Jenner oil field, Southeast Alberta, JCPT, March 1999). As illustrated in FIG. 8, a test on a horizontal well was inconclusive (AOSTRA (1999)).

4) Cyclic CO₂ stimulation is also a method to recover incremental oil. (Patton et al, Carbon Dioxide Well Stimulation: Part 1—A parametric study, JPT, August 1982). As illustrated in FIG. 10, process efficacy drops off dramatically for heavier oils.

Because of the limitations of the prior art, there is a need for a remediation process that reacts to the cresting/coning in oil wells, preferably heavier oil wells.

SUMMARY OF THE INVENTION

The following terms and acronyms will be used herein:

AOSTRA Alberta Oil Sands Technology Research Authority

AWACT Anti-Water Coning Technology

UNITAR United Nations Institute for Training and Research

JCPT Journal Canadian Petroleum Technology

CIM Canadian Institute of Mining

SPE Society of Petroleum Engineers

JPT Journal Petroleum Technology

SAGD Steam Assisted Gravity Drainage

GOR Gas to Oil Ratio

OC Oil Cut

Kro Relative permeability to Oil

Krw Relative permeability to Water

SACT Steam Anti Coning/Cresting Technology

STB Stock Tank Barrels

SRC Saskatchewan Research Council

HZ Horizontal (well)

VT Vertical (well)

OSR Oil to Steam Ratio

SOR Steam to Oil Ratio

DHWS Down Hole Oil Water Separator

EOR Enhanced Oil Recovery

REC Recovery

OOIP Original Oil in Place

25

Because of the need for a cresting/coning remediation process, SACT is a process that adds steam to the cone/crest zone and heats oil in the cone/crest zone and at the cone/crest zone edges. In a preferred embodiment, the steam addition is followed by a soak period to allow further heating of oil and to allow gravity to cause a re-saturation of the cone/crest zone. Preferably after the soak period, the oil well may then be returned to production.

30

Preferably, the SACT process is applied to 1) heavy oils where native oil viscosity is too high to allow rapid oil re-saturation of the cone/crest zone, preferably where the viscosity is >1000 cp, and 2) bitumen (SAGD) wells.

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According to a primary aspect of the invention, there is provided a cyclic remediation process to restore oil recovery from a primary well that has watered off from bottom water encroachment (cone or crest) whereby:

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- (1) The primary well has a produced water cut in excess of 95% (v/v),
- (2) The oil is heavy oil, preferably with in-situ viscosity >1000 cp, and wherein said process comprises:
- (3) Injection of steam in the cone/crest zone preferably by a steam slug with a preferred volume of 0.5 to 5.0 times the cumulative primary oil production, preferably where said steam is measured as water,
- (4) After steam injection is complete, the well is shut in for a soak period,
- (5) The well is then produced until the water cut exceeds 95%

50

In a preferred embodiment of the process the well was previously steamed.

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Preferably the steam is injected using the existing primary oil production well.

In an alternative embodiment, the steam is added using a separate well.

60

In another embodiment of the process, the primary well is a horizontal well and bottom water encroachment forms a water crest zone beneath the primary well.

In another embodiment, in the event that the primary well is not suitable for steam injection, several substantially parallel horizontal wells may be linked with a separate perpendicular horizontal well completed in the steam crest zone of each of the parallel horizontal wells.

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Preferably several of the substantially parallel horizontal wells may be linked at or near the midpoint of the horizontal well lengths, in the crest zone.

In another embodiment, the heavy oil is bitumen ($\text{API} < 10$; $\mu > 100,000$ cp).

In another embodiment, there is provided a cyclic remediation process to restore bitumen recovery from a bitumen well that has watered off from bottom water encroachment (cone or crest) whereby:

- (1) The primary well has a produced water cut in excess of 70% (v/v),
- (2) Injection of steam in the cone/crest zone preferably by a steam slug with a preferred volume of 0.5 to 5.0 times the cumulative primary oil production, preferably where said steam volumes is measured as water volumes,
- (3) After steam injection is complete, the well is shut in for a soak period,
- (4) The well is then produced until the water cut exceeds 70%.

In another embodiment, the bitumen production well is used for steam remediation injection.

In another embodiment, steam injection rates (measured as water) are 0.5 to 5.0 times fluid production rates when the primary well had watered off.

Preferably the steam quality at the steam injector well head is controlled between 50 and 100%.

Preferably the well is shut in for a soak period of 1 to 10 weeks.

BRIEF DESCRIPTION OF THE DRAWINGS

FIGS. 1A and 1B respectively depict the water cone lean zone of a vertical production well and the water crest lean zone of a horizontal production well

FIG. 2 depicts a SAGD Bitumen Lean Zones (Bottom Water)

FIG. 3 depicts the prior art DHOWS concept

FIG. 4 depicts the prior art Reverse Coning Control

FIG. 5 depicts the AWACTION effects on Relative permeability

FIG. 6 depicts the Incremental AWACTION Reserves in pre and post AWACTION oil recovery

FIG. 7 depicts the Frequency distribution of incremental oil following AWACTION

FIG. 8 depicts oil production and oil cut history of horizontal wells pre and post AWACTION

FIG. 9 depicts the AWACTION laboratory tests and water-oil ratios versus time of various gases

FIG. 10 depicts the stimulation of CO_2 of Oil Wells versus oil viscosity

FIG. 11 depicts the injection of steam via a steam string for SACT according to an embodiment of the present invention

FIG. 12 depicts the injection of steam via a separate steam injector for SACT according to an embodiment of the invention

FIG. 13 depicts SACT well for Crested Heavy Oil Wells

FIG. 14 depicts SAGD partial coning/cresting

FIG. 15 depicts heat conducted around a hot well

FIG. 16 depicts SACT simulation in vertical and horizontal wells according to the present invention

FIG. 17 depicts SACT simulation in horizontal wells

FIG. 18 depicts SACT Scaled Physical Model Steam Injection Rates

FIG. 19 depicts SACT Scaled Physical Model Steam Slug Sizes

FIG. 20 depicts SACT Scaled Physical Model Water Cut Offs

FIG. 21 depicts SACT Scaled Physical Model Horizontal Well Lengths

DETAILED DESCRIPTION OF THE INVENTION

SACT is a remediation process for heavy oil wells (or for SAGD) that have coned or crested due to bottom water encroachment. The process is cyclic and has the following phases:

- (1) The primary production well is shut-in due to high (or excessive) water cuts from bottom water encroachment (coning or cresting).
- (2) Steam is injected into the cone or crest zone with at least a sufficient volume to displace the bottom water in the cone/crest zone.
- (3) The well is shut-in to soak for a period of time (weeks-months). This allows heat from the steam to be conducted to oil in/near the cone/crest zone, reducing the oil viscosity by heating and allowing the oil to re-saturate the cone/crest zone by gravity.
- (4) The well is put back on production.
- (5) The process can be repeated.

One of the issues for a conventional heavy oil production facility is that primary production wells are not designed for steam injection. The production wells can be damaged by thermal expansion, and the cement isn't designed for high temperature operations. This problem can be mitigated by one of the following options:

- (1) As illustrated in FIG. 11, the use of an injection string **80** with separate tubing (and insulation) for steam **90** injection to minimize the heating of the primary well **110**; or
- (2) As illustrated in FIG. 12, drill and thermally complete a separate steam injection well **100** for remediation of a single well **130**; or
- (3) As illustrated in FIG. 13, drill and thermally complete a separate steam injection well **100** linked to several wells **140 150 160**, allowing for simultaneous remediation.

Referring to FIG. 11, an injection steam string **80** with separate tubing and insulation to minimize the heating of the primary well **110** is shown. The well in this instance may be vertical or horizontal.

Referring to FIG. 12 a separate steam injection well **100** is used to inject steam in to the water cone **120** according to the present invention. In this Figure, a vertical well configuration is shown for use with a single primary production well **130**.

Referring to FIG. 13 a SACT steam injector horizontal well **100** is linked to a plurality of horizontal producing wells **140, 150 and 160** to ensure crested heavy oil wells are simultaneously remediated according to the present invention.

Bitumen SAGD is a special analogous case for SACT process applications. If the SAGD project has an active bottom water **20**, we can expect that the lower SAGD production well will cone/crest eventually (FIG. 2). Bitumen ($< 10\text{API}$, $> 100,000$ cp in situ viscosity) is heavier and more viscous than heavy oil (1000 to 10,000 cp), but after bitumen is heated it can act similarly to heavy oil.

If bitumen is above an active bottom water, SAGD can, theoretically, produce bitumen without interference from bottom water, if process pressures are higher than native reservoir pressure, if the pressure drop in the lower SAGD production well doesn't breach this condition, and if the bottom of the reservoir (underneath the SAGD production well) is "sealed" by high viscosity immobile bitumen underneath the production well. But, this is a delicate balance for the following reasons:

- (1) Steam pressures can't be too high or a channel may form allowing communication with the bottom water. Subsequent fluid losses can, at best, reduce efficiency and at worst, shut the process down. Water production will be less than steam injection.
- (2) The initial remedy to this is to reduce pressures. But, steam pressures can't be too low or water will be drawn from the bottom water zone into the production well (coning/cresting). Water production will exceed steam injection. Also, one of the process controls for SAGD is sub-cool (steam trap control) assuming the near-well bore zone is at saturated steam temperature. This control will be lost when bottom water breaches the production well.
- (3) As illustrated in FIG. 14, if the SAGD reservoir is inhomogeneous or if the heating pattern is inhomogeneous, the channel or the cone/crest can be partial and the problem can be accelerated in time.
- (4) Initially, cold bitumen underneath the production well will act as a barrier to prevent channeling, coning or cresting. But, as the SAGD process matures, after a few years, the bottom bitumen will be heated by conduction (FIG. 15) and in situ viscosity will be similar to heavy oil, with increased chances of channeling, coning and cresting.

Once the production well has coned/crested, the SACT process can be applied. Unlike heavy oil, the SAGD production well has been thermally completed and it can be used as a SACT steam injector.

Again, the SACT process is cyclic with the following steps:

- (1) Shut-in the SAGD producer and convert it to a steam injector.
- (2) Maintain target pressures in the SAGD steam chamber closer to but slightly above in situ pressures by using the steam injector well.
- (3) Inject a slug of steam into the SAGD production well.
- (4) Shut in both SAGD wells for a soak period (weeks-months) to allow bitumen to be heated and to re saturate the cone/crest area.
- (5) The process can be repeated.

EXAMPLE

Nexen conducted a simulation study of SACT using the Exotherm model. Exotherm is a three-dimensional, three-phase, fully implicit, multi-component computer model designed to numerically simulate the recovery of hydrocarbons using thermal methods such as steam injection or combustion.

The model has been successfully applied to individual well cyclic thermal stimulation operations, hot water floods, steam floods, SAGD and combustion in heavy hydrocarbon reservoirs (T. B. Tan et al., Application of a thermal simulator with fully coupled discretized wellbore simulation to SAGD, JCPT, January 2002).

We simulated the following reservoir:

Pressure - 6200 kPa
 Temperature - 28 degrees Celsius
 Porosity - 33%
 Initial water Sat. - 30%
 In-situ viscosity - 2000 cp
 Oil pay - 16 m
 Bottom water - 10 m
 HZ well spacing - 75 m
 HZ well length - 1000 m

We simulated SACT after primary production coned/crested wells. For a vertical well we used steam slug sizes from 50-200 m³. For horizontal wells we used slug sizes an order-of-magnitude larger.

FIG. 16 shows simulation results for SACT and a comparison of horizontal and vertical well behavior. Based on the simulation results, the following is observed:

- (1) The primary production period for vertical wells is much shorter than for horizontal wells—about a quarter of the time—until the wells are watered off
- (2) The primary productivity of vertical wells is about a factor of 10 less than for horizontal wells. SACT productivities maintained this ratio.
- (3) The SACT cycle times are larger for horizontal wells. In the period shown in FIG. 16—about 3 yrs.—we have 11 SACT cycles for vertical wells compared to only 3 cycles for horizontal wells.

FIG. 17 shows a comparison of SACT for horizontal wells, where the steam injection was applied at the heel and at the mid-point of the wells.

Based on the results shown in FIG. 17, the following is observed:

- (1) Primary recovery factor for a horizontal well is about 9% OOIP.
- (2) The SACT process, over a period of 2 years after primary production, recovered an extra 5% OOIP for SACT applied at the heel of the horizontal well and an extra 12% OOIP for SACT applied at the mid-point of the horizontal well. This incremental RF is significant when compared to primary production.
- (3) The first cycle of SACT applied to the mid-point of the horizontal well produced a production profile better than the primary producer.

In 1995-96 Nexen contracted SRC to conduct a scaled-physical model test of the SACT process based on the following:

14 m oil pay column
 16 m active bottom water column
 32% porosity
 4D permeability
 3600 cp in-situ viscosity
 980 kg/m³ oil density (API=12.9)
 28° C., 5 Mpa reservoir T,P

150 m well spacing, 1200 m horizontal well length

Tables 2, 3, 4 and FIGS. 18, 19, 20, 21 present the results of the studies. Based on the results of these studies, the following was observed:

- (1) For horizontal wells, steam slug sizes varied from about 36,000 to 54,000 cubic meters (225 K bbl to 340 K bbl) (Table 2). For vertical wells, steam slug size varied from about 500 to 1100 cubic meters (3100 to 7000 bbls. At least within the range studied, steam slug size is not very sensitive (FIG. 19)). The slug size ratio horizontal/vertical is about 50-70. (Table 3).
- (2) Steam injected rate varied from about 300 to 400 m³/d (1900 to 2500 bbl/d) for horizontal wells (Table 2) and at about 9.3 m³/d (60 bbl/d) for vertical wells (Table 3). The horizontal/vertical ratio, defined as the ratio of length of contact with oil portion of reservoir, is from about 30 to 43. Steam injection rate is not a sensitive variable (FIG. 18).
- (3) The SACT process was tested for 4 to 7 cycles for horizontal wells and 3 cycles for vertical wells.
- (4) Recovery factors varied from 25 to 36% for horizontal wells and 36 to 43% for vertical wells (OOIP is much higher for horizontal well patterns).

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- (5) OSR is the key economic indicator. Horizontal wells SACT OSR varied from 0.73 to 0.95 (SOR for 1.4 to 1.1). Vertical well OSR varied from 0.47 to 0.56. In comparison, a good SAGD process has an OSR=0.33
- (6) FIG. 20 shows water cut offs (when production is stopped) are best at higher levels (90% vs. 50%).
- (7) FIG. 21 shows better performance for longer horizontal wells (300 m vs. 150 m) but it is not necessarily at optimum lengths.

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- (6) Application to SAGD bitumen producer with bottom water
- (7) Cyclic remediation process (not continuous)
- (8) Applies to both horizontal and vertical wells
- (9) Steam injection rate limits
- (10) Steam quality limits

Other embodiments of the invention will be apparent to a person of ordinary skill in the art and may be employed by a person of ordinary skill in the art without departing from the spirit of the invention.

TABLE 2

Scaled Physical Model Test Results Horizontal Wells					
Reservoir Conditions:					
Porosity (%)	35.8	35.0	34.8	35.7	35.2
OOIP (m ³)	816100	819300	817500	798700	785000
Oil Sat. (%)	93.3	94.0	94.1	91.1	91.1
Prim. Prod. (% OOIP)	2.8	1.7	5.	3.7	2.7
Tests:					
No. of Cycles	7	6	4	6	7
Run length (yrs)	21.9	20.9	16.0	21.0	24.3
Stm. inj. rate (m ³ /d)	301.4	401.6	299.1	300	300
Stm. slug size (m ³)	36120	48200	53840	36000	54000
Cum. stm. inj. (m ³)	260187	291663	219269	217751	384664
Steam Q (%)	70	70	70	70	70
Cycle shut off (% w)	90	90	90	50	50
Performance:					
Recovery (% OOIP)	29.0	26.1	25.0	26.2	36.4
Cum. OSR	.91	.73	.93	.95	.73
Oil Rate (m ³ /cd)	29.6	28.0	34.9	27.3	32.2
Wat. Rate (m ³ /cd)	53.5	48.5	33.2	3.4	6.4

(SRC (1997))

Where (1) primary production used in all cases to establish water crests.

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Based on the studies and simulations discussed herein, it appears that the SACT process of the present invention works best for heavy oil cone/crests, since heating the zone and the oil can improve oil mobility dramatically compared to light oils.

If the heavy oil is produced using horizontal production wells and crests have formed from an active bottom water, a preferred way to link the well crests is a substantially perpendicular horizontal well about mid-way along the crest. (FIG. 13) The well is thermally completed for steam injection.

The steam slug should be preferably 0.5 to 5.0 times the cumulative primary oil production, on a water equivalent basis (ie. steam measured as water volumes). The steam injection rate is determined by injection pressures—preferably no more than 10% above native reservoir pressures at the sand face.

Enough time is needed for the steam to heat surrounding oil and the oil to re saturate the cone (crest zone)—based on the above, it is preferably between 1 to 10 weeks after the end of the steam cycle.

The process may be repeated when the water cut in produced fluids exceeds about 95% (v/v).

Some of the preferred embodiments of the present invention are provided below.

- (1) Heavy oil (>1000 cp in-situ viscosity)
- (2) Well geometry to connect/link to parallel primary horizontal producers in cresting zone.
- (3) Preferred linkage near mid-point of horizontal producers.
- (4) Steam slug size limits
- (5) Soak period limits

TABLE 3

SACT Scaled Physical Model Tests Vertical Wells		
Reservoir Conditions:		
OOIP (m ³)	4205	4205
Spacing (m ²)	900	900
Oil Sat. (%)	94.0	31.2
Prim. Prod. (% OOIP)	15.3	14.1
Gas Cap	yes ⁽¹⁾	no
Tests:		
No. of Cycles	3	3
Run length (yrs)	5.8	6.5
Stm. inj. rate (m ³ /d)	9.3	9.3
Stm. slug size (m ³)	1116	558
Cum. stm. inj. (m ³)	3348	1674
Performance:		
Recovery (% OOIP)	43.4	35.9
Cum. OSR	0.47	0.56
Oil Rate (m ³ /cd)	0.86	0.63
Wat. Rate (m ³ /cd)	3.19	0.84

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TABLE 4

SACT Scaled Physical Model Tests Vertical vs. Horizontal Wells					
	End of Primary Production	End of cycle 1	End of cycle 2	End of cycle 3	End of cycle 4
Vertical Well (Win 207)					
time: start of primary production	3.0	4.2	5.7	6.5	—
: start of EORR	—	1.2	2.7	3.5	—
OSR: in cycle	—	0.39	0.73	0.56	—
: cumulative	—	0.39	0.56	0.56	—
Recovery: in cycle	14.1	5.3	9.8	6.3	—
(% OOIP): cumulative	14.1	19.4	29.2	35.9	—
Horizontal Wells					
time: start of primary production	6.0	11.6	15.6	18.1	22.1
: start of EORR	—	5.6	9.6	12.1	15.1
OSR: in cycle	—	1.17	1.06	0.70	0.77
: cumulative	—	1.17	1.12	0.98	0.93
Recovery: in cycle	5.9	7.8	13.1	4.7	5.3
(% OOIP): cumulative	5.9	7.8	20.9	25.6	30.9

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The invention claimed is:

1. A cyclic remediation process to restore oil recovery from a primary oil production well that has watered off from bottom water encroachment whereby:

- (a) the primary oil production well has a produced water cut in excess of 95% (v/v);
- (b) the oil is heavy oil, with in-situ viscosity >1000 cp; wherein said process comprises:
- (c) injecting a steam slug with a volume of 0.5 to 5.0 times the cumulative primary oil production, with steam volumes measured as water volumes;
- (d) shutting in the well for a soak period after the steam injection is complete; and
- (e) producing the well until the water cut exceeds 95%.

2. The process according to claim 1, where the primary oil production well has been previously steamed.

3. The process according to claim 1, where the steam is injected using the existing primary oil production well.

4. The process according to claim 1, where the steam is added using a separate well.

5. The process according to claim 1, where the primary oil production well is a horizontal well and bottom water encroachment forms a water crest zone beneath the primary oil production well.

6. The process according to claim 5, where the primary oil production well is not suitable for steam injection and several substantially parallel horizontal wells are linked with a separate substantially perpendicular horizontal well completed in the steam crest zone of each of the substantially parallel horizontal wells.

7. The process according to claim 6, where the separate substantially perpendicular horizontal well is linked at or near the midpoint of the horizontal well lengths, in the crest zone.

8. The process according to claim 1, where the heavy oil is bitumen.

9. The process according to claim 8, wherein the bitumen has API<10 and μ >100,000 cp.

10. A cyclic remediation process to restore bitumen recovery from a bitumen production well that has watered off from bottom water encroachment whereby:

- (a) the bitumen production well has a produced water cut in excess of 70% (v/v);
- (b) injecting a steam slug with a volume of 0.5 to 5.0 times the cumulative bitumen, with steam volumes measured as water volumes;
- (c) shutting in the well for a soak period after the steam injection is complete; and
- (d) producing the well until the water cut exceeds 70%, wherein bitumen is an in-situ hydrocarbon with <10 API gravity and >100,000 cp. in-situ viscosity.

11. The process according to claim 10, where the bitumen production well is used for steam remediation injection.

12. The process according to claim 10 where steam injection rates are 0.5 to 5.0 times fluid production rates when the primary well had watered off.

13. The process according to claim 10 where steam quality at the steam injector well head is controlled between 50 and 100%.

14. The process according to claim 10 where the well is shut in for a soak period of 1 to 10 weeks.

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